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REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	**§ §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

COMMENTS OF THE
SOLAR ENERGY INDUSTRIES ASSOCIATION

COMES NOW the Solar Energy Industries Association (SEIA) and files these Comments in response to the Commission's Questions for Comment filed in this proceeding on August 2, 2021.

Executive Summary

- Solar generation resources and other inverter-based resources (IBRs) can operate as dispatchable resources in ERCOT today and provide ancillary services if the market signals support that mode of operation. To date, though, the ERCOT market signals have indicated a preference for maximum energy output from solar generation due to its low cost rather that operating as a dispatchable resource. IBRs also have the potential to respond to ERCOT (or grid) signals quickly and accurately.
- The Commission should not condition application of the ORDC or participation in the energy market on participation in the day-ahead market (DAM). For energy, the DAM is a financial market, not a reliability market, since there is no actual operational obligation imposed. The financial obligations accepted in the DAM also essentially eliminate application of the ORDC in real time for the resources meeting the DAM obligations.
- The Commission should review ERCOT's work on NPRR 667 to evaluate potential ancillary service reform. Any new services should be technology neutral to encourage the most competitive provision of the services. Cost allocation of ancillary services should remain with load serving entities.
- Significant opportunities are untapped with regard to residential demand response and the capabilities of distributed energy resources. Individually and working together, both of these can significantly and directly support reliable operations of the grid.
- ERCOT should consider the development of ancillary services that take better advantage of current and developing capabilities of IBRs to support reliable grid operations quickly and accurately, including managing inertia, voltage support, and frequency.

Introduction

SEIA is the national trade association of the solar energy industry. Through advocacy and education, SEIA and its members are building a strong solar industry to power America. As the voice of the industry, SEIA works to make solar a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy. SEIA represents solar companies across a variety of solar energy technologies, including photovoltaic ("PV"), solar water heating, and concentrating solar power ("CSP"). Additionally, SEIA represents diverse solar companies providing utility-scale generation community solar, and customer-sited solar and storage solutions.

Comments

1. What specific changes, if any, should be made to the Operating Reserve Demand Curve (ORDC) to drive investment in existing and new dispatchable generation? Please consider ORDC applying only to generators who commit in the day-ahead market (DAM). Should that amount of ORDC-based dispatchability be adjusted to specific seasonal reliability needs?

With the focus of this question on "dispatchable generation," it is important to recognize that all generation resources, including inverter-based resources (IBRs) such as solar and wind generators, are capable of being dispatchable resources if the market mechanisms are designed to encourage it. As discussed more below, recent studies conducted on both wind and solar assets by the CAISO illustrate just how accurately these resources can provide fundamental grid services, often much better and more cost effectively than traditional fossil-fueled generators.[1] Smart controls on inverter-based technology give operators a mechanism to hold back and release energy as needed. In other words, solar can be used to create cost-effective, flexible dispatch that supports supply and demand balancing. While ERCOT's current market design encourages IBRs to prioritize maximized delivered energy over providing ancillary services to ERCOT, that does not mean that these resources are not "dispatchable generation."

Traditionally, utility-scale solar projects have been designed to produce their maximum potential output in any given moment, pursuant to available irradiance. As penetration of variable renewable resources in ERCOT increases, the Commission and ERCOT should be looking at utility-scale solar and wind to provide not just energy, but the full suite of services currently proffered by the conventional fossil fuel fleet today. As a utility-scale solar generators transition from a market design that seeks maximum energy delivery to one that seems all resources to be

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[1] *See* Cal. Independent System Operator et al., *Avangrid Renewables Tule Wind Farm Demonstration of Capability to Provide Essential Grid Services*, March 11, 2020, *available at*: http://www.caiso.com/Documents/WindPowerPlantTestResults.pdf (a joint study also involving NREL, Avangrid, and General Electric); *see also* National Renewable Energy Lab., *Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant*, March 2017, *available at*: https://www.nrel.gov/docs/fy17osti/67799.pdf (in collaboration with CAISO and First Solar).

fully dispatchable by the grid operator, the ability for solar generation resources to also deliver reliability services will be evident.

As noted above, IBRs such as solar can respond incredibly accurately to dispatch signals and do so in exceedingly rapid timescales. For example, new IBRs are capable of monitoring the conditions of the grid at the point of interconnection and controlling each individual inverter at a project site (which can number in the hundreds) to respond to those conditions in roughly 300-500 milliseconds – significantly faster than the best-in-class fossil unit. More specifically, the controls allow for the retention of headroom (upward ramping ability) that can provide ERCOT additional generation availability that can be released to the grid when demand is greater. This added flexibility allows large-scale solar to provide grid reliability services, such as frequency regulation, that out-perform conventional generation sources. Such capabilities also can enable ERCOT to more effectively manage resources to maintain grid balance during daytime and early evening transitions.

IBRs are able to outperform fossil units in their ability to accurately follow grid dispatch signals, at a significantly more granular level. The First Solar / NREL / CAISO report states that "regulation accuracy by the PV plant is 24-30 points better than fast gas turbine technologies."[2] Modeling conducted by Energy and Environmental Economics ("E3") on behalf of First Solar and Tampa Electric Company ("TECO") and published in October 2018 quantified the benefits of treating utility-scale solar as a flexible, dispatchable resource.[3] The more integrated the resource became with unit commitment and dispatch decisions, the more benefits redounded to consumers.

E3 modeled utility-scale solar as capable of providing both footroom (allowing the resource to provide downward reserves in cases where demand is lower than forecasted) and headroom (under-scheduling the resource day-ahead to reduce its own forecast error and provide upward ramping capabilities such as regulation and spinning reserves), allowing the production cost model to leverage this zero marginal cost resource in new ways. This resulted in reduced unit commitments of the fossil fleet, as they were no longer as critical in providing balancing services. Removing some of those units from the dispatch stack also removed their minimum generation

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2 *Id.*, at p .22.

3 Nelson, J. et al., *Investigating the Economic Value of Flexible Solar Power Plant Operation*, Oct. 2018, *available at*: https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf (a collaborative study involving Energy and Environmental Economics, First Solar, and Tampa Electric Company).

levels (i.e., Pmin), creating additional room for renewables to operate and reducing the need for curtailment. As such, at very high penetration levels, more renewables were delivered to the grid even though the opportunity to be curtailed was greater. This resulted in a significant increase in production cost savings to consumers and reduced emissions on the grid.

IBRs also are capable of providing reactive power, and solar plants can provide reactive power even at night. Inverters are capable of providing reactive power more effectively than fossil units. Markets such as PJM and MISO allow for cost-based compensation to renewable resources that provide reactive power support to the grid.

This focus on the fact that solar and wind generation and all other IBRs are dispatchable generation in the context of this question is to emphasize that the ORDC should continue to be implemented in a manner to drive investment in ***all*** existing and new generation.

The Commission should not condition the availability of ORDC to being paid only to those generators who commit in the DAM. While requiring all generation resources to offer a minimum commitment in the DAM is a common feature of capacity markets, it is not consistent with ERCOT's energy-only market design. Generation resources in capacity markets are paid to be available. In contrast, in ERCOT, there is no availability standard for generation resources and the DAM is a voluntary market that enables QSEs and individual generators to secure their financial position in the real-time market.

The DAM facilitates ERCOT's energy-only market structure. The DAM it is not a reliability market that imposes a commitment for a particular resource to generate in the real-time market. QSEs that submit bids in the DAM do not have to link their bids to actual units. To meet their obligation from the DAM in the real-time market, the QSE may determine which units will actually operate. Even when a particular generation resource has taken a financial obligation in the DAM, it may choose to operate itself, but it also has the option to pay another generator to meet that obligation. By taking an obligation in the DAM and agreeing to sell energy at a negotiated price in real time, the generator also essentially eliminates the application of the ORDC to the energy it is obliged to deliver in the real time. This is because any additional financial benefit that results from the ORDC that has not already been anticipated in the DAM is received by a counter-party to offset their exposure to that incremental expense. Thus, there is a disconnect between the financial obligation that is the focus of the DAM and the focus of the ORDC on real-time operation and performance.

Limiting the application of ORDC to only those generators that commit in the day-ahead market also may adversely impact grid reliability. Unless the Commission were to apply the ORDC to all the capacity of each resource that committed in the DAM, this construct could have the perverse result of making less valuable additional energy above the amount procured from generators in the DAM even though the additional energy was necessary to meet increased demand. The economic signal to increase output or bring additional capacity to the market (such as the use of duct burners in combined cycle gas turbines) would be squashed at the very time it should be the highest. Moreover, a discriminatory application of the ORDC also would undermine the ERCOT settlement process since ERCOT would need to differentiate the settlement of energy without the ORDC applied for both generation and load when the load has contracted for energy from a particular resource that did not have the ORDC applied to their energy. The load should not be charged energy prices that reflect application of the ORDC when the energy they purchased did not have it applied in the first place.

2. Should ERCOT require all generation resources to offer a minimum commitment in the day-ahead market as a precondition for participating in the energy market?

a. If so, how should that minimum commitment be determined?

b. How should that commitment be enforced?

For the same reasons discussed above regarding why application of the ORDC should not be conditioned on a generator committing in the DAM, the Commission also should reject imposing a must-offer obligation on generators in order for them to participate in the real-time energy market. Looked at in the context of Winter Storm Uri, additional participation in the DAM would not have delivered any more generation capacity in the real-time market. By the same token, it would have been a perverse result if imposing a prerequisite obligation to bid in the DAM were to have prevented generation from participating in the real-time market if it otherwise could have done so.

A regulatory requirement that generation resources must participate in the DAM in order to participate in the real-time energy market also could eliminate the financial benefit realized from voluntary participation today. Since this new obligation would be unit specific, the flexibility of a QSE to operate the most cost-effective resources in a portfolio in real-time could be restricted compared to today. In addition, a minimum participation threshold that is too high could cause DAM market prices to be suppressed relative to the real-time market. A regulatory requirement that leads to lower capacity commitments could cause the real-time market prices to be lower than the DAM. In either case, the efficiency of the financial positions from the DAM relative to the real-time market would be undermined. The best approach for the Commission is to avoid increasing the regulatory interference in the DAM and its interactions with the real-time market.

3. **What new ancillary service products or reliability services or changes to existing ancillary service products or reliability services should be developed or made to ensure reliability under a variety of extreme conditions? Please articulate specific standards of reliability along with any suggested AS products. How should the costs of these new ancillary services be allocated.**

The Commission should consider the significant analysis and work ERCOT already performed in connection with the development of NPRR 667, Ancillary Service Redesign, that ERCOT filed for consideration on November 18, 2014.[4] ERCOT's goal was to improve the ancillary services available to ensure reliable operation of the grid based on changes that have been occurring for years.

Any new or modified ancillary services or reliability services should be able to be provided by all technology types. Once the Commission and ERCOT provide clear standards for the services they determine are necessary to address particular conditions, innovation in the competitive market will address those needs in the most economical and efficient way possible, and often bring forward new technological solutions that can provide better results than the regulatory process could have envisioned, such as customer-sited solar and storage.

Cost allocation for current and new ancillary services should continue to be as efficient as possible and allow market participants to self-provide and hedge ancillary service obligations to the extent possible in what are less liquid markets and where the actual obligations to ERCOT are routinely subject to after-the fact adjustments. The current approach of recovering the costs of ancillary services from load continues to be the best approach to meet these goals. In addition, this approach is consistent with the requirements of amendments to Utilities Code § 35.004(h) enacted during the last legislative session since ancillary services are procured to ensure a reliable supply of energy **to meet the needs of load**, and this cost allocation methodology is non-discriminatory.

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[4] *See* http://www.ercot.com/mktrules/issues/NPRR667#keydocs.

4. Is available residential demand response adequately captured by existing retail electric provider (REP) programs? Do opportunities exist for enhanced residential load response?

Existing retail programs do not capture the available potential of residential demand response. In addition, the Commission also should not overlook the opportunities for aggregated customer-sited solar and storage to serve generation needs, increase resiliency, and reduce loads especially at critical times. Significant opportunities are untapped with regards to residential demand response and distributed energy resource aggregations operating together to serve as Virtual Power Plants (VPPs),[5] *i.e.*, grid resiliency assets which can provide dynamic capacity (energy exports) and ancillary services to the electric grid as successfully as peaker generation capacity and grid-scale storage. VPPs area proven resiliency tool to help the grid operator, load serving entities, and TDUs coordinate more accurate, efficient, and predictable non-critical load shed events in partnership with their enrolled customers, helping avert rolling outages or allowing customers to ride through extended outages. Further, operating as a VPP, these aggregated participants can cycle charging and discharging behavior to (i) maximize peak delivery of dynamic capacity (dispatchable energy reserves that can be exported when they are needed most), and (ii) respond to Automatic Generation Control (AGC) signals and cycle charging and discharging behavior to provide ancillary services that balance variations in demand and system frequency and voltage on a second-by-second basis. For example, a utility-administered aggregation in Vermont, in which customers may lease a battery or bring their own device into the program, has allowed customers to use their home batteries to ride through up to four-day outages during a winter storm seamlessly without grid power.[6] Working with a third-party aggregator, these home batteries are

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[5] A Virtual Power Plant (VPP) is an aggregated resiliency asset compromised of electric devices interconnected to the distribution system: home batteries paired with solar, community microgrids and storage, and any other grid-responsive equipment that can be collectively modeled and dispatched to provide load reduction, exports of energy and self-directing behaviors that deliver ancillary services through a networked software platform managed by an energy management/aggregation service provider. Just like a natural gas plant, a VPP is fully dispatchable. A VPP comprised of demand response assets can provide a MW to the grid by reducing demand on the system at key times. A VPP made up of energy storage devices and rooftop solar also can provide energy exports and ancillary services to the grid on the same terms as a utility-scale battery or thermal synchronous resource.

[6] *See* https://greenmountainpower.com/gmp-customers-keep-lights-on-with-stored-low-carbon-energy-during-storm-outages/ (accessed 8/12/2021); as of August 2021, the Green Mountain Power battery leasing program has 2,000 enrolled home battery systems aggregated to a 10 MW plant, powering 7,500 homes off-grid during peak hours (*see https://greenmountainpower.com/gmp-launches-new-comprehensive-energy-home-solution-tesla-lower-costs-customers/*).

also providing frequency regulation service to ISO-NE.[7] In another timely use case, a battery aggregator is currently partnering with a Southern California utility to run an 8,000-residence VPP. As an enrollment incentive, the aggregation company offers enrolled customers a heavy up front discount on their home battery purchase in exchange for being able to provide dynamic capacity and network support services from the excess capacity that the customer is not using for onsite consumption.[8] In South Australia, the energy-only AEMO market has allowed for aggregated DERS/VPPs to participate in all ancillary services markets since 2017, most recently expanding their reach to unlock the full potential of residential aggregations in a 2-year pilot, which has allowed over 4,500 households to participate in providing 6-second, 60 second, and 5-min frequency contingency grid services and be compensated through their retail energy providers.[9]

There is potential for REPs on their own or working with third-party service providers to offer these innovations to Texas customers, but it has not been realized to date because of limitations in market design that do not allow residential solar-storage customers or other behind-the-meter DERs to provide the full suite of grid services which generators can provide in ERCOT. In order to enable these resources to be available in the ERCOT region, the Commission should require ERCOT to work with stakeholders to develop clarifications to its market rules, that have been designed for large single site resources on the transmission grid, to allow aggregations of resources on the distribution grid to participate in wholesale energy and ancillary service markets. The state's TDUs have a critical role to also play in in this area. Utilities must lead on interconnection service rule reforms which will recognize and embrace new technologies that reduce customer DER interconnection costs and simplify installation. Simultaneously, utilities must bring together the value proposition of VPPs as a grid reliability tool *and* as a system planning tool. The Commission should ensure that TDUs are developing robust analyses for transmission and distribution infrastructure spending which account for the cost deferral value of DERs as load growth management tools.[10]

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7 https://www.energy-storage.news/tesla-powerwalls-hooked-up-to-provide-grid-frequency-balancing-in-vermont-utility-pilot/.

8 https://www.energy-storage.news/time-to-take-virtual-power-plants-seriously-swell-energy-creates-asset-class-from-customer-assets/.

9 See AEMO Virtual Power Plant Demonstrations, Knowledge Sharing Report 3 (February 2021), available at https://aemo.com.au/-/media/files/initiatives/der/2021/vpp-demonstrations-knowledge-sharing-report-3.pdf?la=en&hash=6050131AD17ADCFD230BDC6437396284.

10 *See, e.g.*, Sunrun, *Building a More Resilient Grid – Home Solar & Storage Mitigate Wildfire Impacts* (March 2019), available at https://www.sunrun.com/sites/default/files/wildfire-mitigation-sunrun.pdf , at pp. 6-7.

The development and incorporation of DERs in ERCOT could result not only in increased resiliency, but significant savings for ratepayers and utilities. A grid that optimizes DERs not only serves local load and reduces peak load but also can lessen the need for some of the distribution infrastructure and transmission buildout. The Commission should ensure DERs are integrated and optimized into ERCOT and regulatory planning using advanced modeling tools like WIS:dom-P.[11] With communication between both sides of the grid (transmission & distribution) with WIS:dom modeling demonstrates an ability for local solar and storage to reshape load and increase an efficient and resilient grid for customers.

6. How can the current market design be altered (e.g., by implementing new products) to provide tools to improve the ability to manage inertia, voltage support, or frequency?

ERCOT's ancillary services products are currently effective in meeting the need for voltage and frequency support. However, ERCOT could improve its ability to manage the grid by contracting with IBRs to provide grid reliability services at a speed and accuracy that traditional thermal resources are not able to meet. IBRs can respond to grid needs far more quickly and more accurately than thermal generation units. In the study by the National Renewable Energy Laboratory (NREL) previously referenced,[12] a 300 MW PV plant was able to match Automatic Generation Control (AGC) signals from the grid operator with less than 1/10th of 1% error during the testing period. At the same time, inverter response times are instant, allowing inverter-based resources to respond to signals in less than one second, while thermal generators usually take at least several minutes or much longer. A conventional combustion turbine can take 20 minutes to meet grid operator commands, or more than 1,000 times as long as a PV resource if such resources were enabled to participate in ERCOT's ancillary service markets.

While ERCOT has continued to indicate that it has adequate inertia on the system, IBRs have the capability to provide additional synthetic inertia if ERCOT were to design and procure an appropriate product. Designed correctly, this is a product that all generation resources could provide. Unlike thermal generators that have spinning mass as an inherent part of their operations and that naturally provides inertia to the grid, IBRs have the ability to provide the same operational

[11] https://www.vibrantcleanenergy.com/products/wisdom-p/

[12] National Renewable Energy Lab., *Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant*, March 2017, *available at*: https://www.nrel.gov/docs/fy17osti/67799.pdf (in collaboration with CAISO and First Solar).

benefit as that form of inertia through the operation of their inverters. The benefit of this "synthetic" inertia recently has been demonstrated in a real life situation Australia by the Hornsdale Power Reserve.[13] In that case, the IBR at issue was a battery, but NREL also has demonstrated that solar generation resources also can provide inertial response.[14]

Nighttime VAR production absorption by solar resources is a potential ancillary service that is largely untapped in ERCOT territory – by stabilizing voltage sags/swells, grid stability could prevent additional resources dropping offline in critical grid conditions.

Conclusion

SEIA appreciates the opportunity to provide these Comments and looks forward to working with the Commission and other interested parties on these issues.

Respectfully submitted,

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13 Giles Parkinson, "Virtual machine": Hornsdale battery steps in to protect grid after Callide explosion | RenewEconomy, Renew Economy, May 27, 2021 (available at https://reneweconomy.com.au/virtual-machine-hornsdale-battery-steps-in-to-protect-grid-after-callide-explosion/).

14 *See* NREL study in Note 5, supra.